Implications of Non-harmonised Renewable Support Schemes

Case Studies

Annex 3 to the CEER public consultation document

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Annex 3 – Case Studies

1 Case Study: The North Seas Countries´ Offshore Grid Initiative

1.1 Background

To date offshore wind farms have been built in shallow waters relatively close to the shorelines of Member States within the EU. The dispersed nature of these developments has led them to be connected to the national network on an individual basis through a single direct connection. This approach is known as a radial connection.

As technology allows offshore generation to be developed and connected further out to sea and as wind farms are deployed closer to each other in comparison to distance to shore, it may become more efficient for multiple wind farms to connect into a common cable which then connects to the onshore network. There is evidence that a number of countries with interests in offshore generation are considering such an approach known as hub connection.

Looking even further into the future it may become possible and beneficial for a renewable generator that is located equidistant from two or more countries to connect into more than one market forming an interconnector. Alternatively, generation may connect into an interconnector which already exists or is being planned at the time. This has led to the proposal of a meshed offshore grid with large amounts of offshore renewable generation connecting into many EU Member States surrounding the North Seas.

In order to investigate the potential for an offshore grid in the North Seas and to ensure that there are no unnecessary barriers to the development of the most efficient approach to connecting the potentially large amounts of offshore wind that are expected, ten Member States surrounding the North Seas have signed a memorandum of understanding to jointly investigate these issues through the North Seas Countries´ Offshore Grid Initiative (NSCOGI).

1.2 RES connected into more than one market

As technology and cost reductions allow RES to be located in areas that were previously not possible, the EU may start to see generation being developed in new areas (e.g. offshore wind generation in the North European seas). The location of this generation may make it more efficient to connect directly into an interconnector rather than into a national network or to connect into more than one market (thus forming a makeshift interconnector). This gives RES the additional benefit of providing more than one market.

Where a RES generator is planning to connect into more than one market, there are a number of considerations with regard to the support provided. Between the countries involved it needs to be decided:

- Which price zone will the generation be included in?
- Which country will provide support through their support scheme? If this is to be shared, how would this be achieved?

- Which country receives the allocation towards achievement of their RES targets?

The first question is being explored through the market and the regulatory issues workstream of NSCOGI. The chosen approach will decide about the rules defining to which market a RES generator directly connected into more than one market is allowed to bid into. A recently discussed case study presented three potential solutions:

(i) When built, the generator must decide which price hub will be its “home hub”. It will therefore always bid into the home hub initially and use long-term contracts to access the other market;
(ii) Create a new North Sea hub which all generators in the North Sea bid into;
(iii) Daily nominations of which market to bid into.

Other relevant questions are for example how the transmission capacity for trading is determined and what information those calculations are based on. How trading will be impacted by the variability and (un)predictability of renewable generation sources (e.g. tidal is more predictable than wind) is another consideration.

1.3 NSCOGI and the cooperation mechanisms

The potential for the development of offshore wind generation in the North Seas also raises challenges for cooperation between Member States. There may be a discrepancy between the Member State in whose seas (territory) the generation is located, the Member State into which the generation is connected and the Member State(s) which wish to fund the generation through a support scheme.

This highlights the importance of the use of cooperation mechanisms for allowing cost and benefit sharing between the countries involved.

The use of the joint project mechanism should allow for joint funding of a project which is connecting into one or both of the countries involved along with the allocated sharing of benefits including renewable contributions. The use of joint projects will allow a Member State to receive contributions towards its renewable targets:

- Whether or not the project lies in the territory of the Member State(s) providing funding;
- Whether or not the project connects into the Member State(s) providing funding; and
- Whether or not the export of generation is into the Member State(s) providing funding.

This should provide the possibility for Member States to focus investment on the most cost efficient locations and for a more economic development of renewable generation in the North Seas at European level.

There are signs that some of the countries with an interest in RES in the North Seas are beginning to investigate the use of joint projects in order to allow the necessary cost and benefit sharing.

The UK is actively considering this issue. The Renewable Energy Roadmap[1] was published by the Department of Energy and Climate Change (DECC) in July 2011 and highlights the importance of being able to fully exploit RES potential in the North Seas. In order to accomplish this goal, DECC states "*We will take powers as early as practicable to enable the "two-way" trade in renewable energy with other Member States where this can secure the greatest benefit for the UK*".

The Netherlands is considering joint projects with the UK. On 30 June 2011, the Dutch parliament adopted a motion in which the Minister of Economic Affairs was asked to "examine with the Government of the United Kingdom if the exclusive economic zones of both countries can be legally opened for the reciprocal realisation of renewable energy projects initiated by the other country".

The UK is also cooperates with Ireland and the Channel Islands to develop the potential for joint projects. The countries involved signed up to the All Island Approach[2] on 20 June 2011 to "cooperate on exploiting the major wind and marine resource in and around the islands". This project will involve developing the legislation that needs to be in place in order to facilitate cross-border allocation of RES support to allow for joint projects.

[1] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf

[2] http://www.decc.gov.uk/en/content/cms/news/pn11_050/pn11_050.aspx

2 Case Study: Renewable support mechanisms in the Single Electricity Market (Ireland and Northern Ireland)

2.1 Background

In 2007, European Union Heads of Government agreed to a binding target that 20% of the EU's energy (across electricity, heat and transport) should come from renewable sources by 2020. The EU Renewable Energy Directive (2009/28/EC) on the promotion of the use of energy from renewable sources came into force in June 2009. Apart from a sub-target of a minimum of 10% in the transport sector applying to all Member States, there is flexibility for each Member State to choose how to achieve their individual target across the sectors. The Directive set a target of 15% renewable energy consumption in the UK and a target of 16% renewable energy consumption for Ireland.

For the UK to meet the EU set target of 15% renewable energy, the UK's renewable energy strategy has proposed that levels of around 32% renewable electricity, 14% renewable heat and 10% renewable transport fuels will be required. Scotland has a target of 40% of its electricity to come from renewable sources.

In Northern Ireland's (NI) Strategic Energy Framework 2009, the Department of Energy Trade and Investment (DETI) has proposed that NI should also adopt a strategic objective to increase the amount of electricity from renewable sources to 40% by 2020.

Ireland's National Renewable Energy Action Plan (NREAP), as required by the Directive 2009/28/EC, sets out the Irish Government's strategic approach and concrete measures to deliver on Ireland's 16% target under the Directive. In that context, the Irish Government has set a target of 40% electricity consumption from renewable sources by 2020, a target of 12% renewable heat by 2020 and a target of 10% from renewable transport[3]. Applying the normalisation rule set out in Annex II of Directive 2009/28/EC, Ireland exceeded its renewable electricity target in 2010 under the previous renewables Directive (2001/77/EC).

2.2 Existing support schemes – UK

The main mechanism for supporting the development of renewable electricity generation in the UK is the Renewable Obligation (RO).

In Northern Ireland Energy Policy has been devolved to the NI Assembly and a separate Northern Ireland RO has been developed by DETI. This sets out the minimum requirement of energy from renewable sources that must be acquired by electricity suppliers in the UK.

3 http://ec.europa.eu/energy/renewables/transparency_platform/doc/national_renewable_energy_action_plan_ireland_en.pdf

The total UK obligation size determines the demand for renewable generation by UK electricity suppliers, is equal to the sum of the obligation size in Northern Ireland and respective schemes in Scotland, England and Wales. Renewable Obligation Certificates (ROCs) are issued for every MW of energy produced from renewable sources.

The supply of ROCs is determined by the total volume of renewable generation in the UK, and banding is used to support different technology groups under each of the respective schemes. Banding involves specifying a multiple of ROCs which could be earned by a supplier which purchased energy from a certain generation technology. For example, tidal stream in England and Wales is eligible for 2 ROCs/MWh. This effectively doubles the level of support available to renewable generators but also increases the number of ROCs in circulation.

The RO does not have fixed targets for installed capacity. Instead a “headroom mechanism” is used to help stabilise the price of ROCs. The headroom mechanism operates by ensuring that there is always a positive gap between demand for ROCs (as expressed in the obligation level set by the RO) and supply and that the gap is kept at as steady a level as possible. As the price of ROCs is driven by the balance of this supply and demand, the headroom mechanism should mean that the ROC price does not fluctuate too far in either direction.

The headroom mechanism involves predicting the total volume of generation and has the potential to result in oversupply of renewable generation. This has resulted in revisions of the headroom level over time.

Additionally in GB there is a feed-in tariff (FIT) scheme available for small scale renewable generation. Under the FIT model, a household or business that uses energy on-site will receive three different income streams:

- Generation tariff – a fixed price for each unit of electricity generated by the small scale generation installation (p/kWh). The price will remain the same throughout the lifetime of an installation’s eligibility for FITs payments.
- Export tariff – providing a fixed payment for exported electricity (p/kWh). The objective of this component of the FIT system is to reduce uncertainty and the difficulty of engaging with electricity market for small-scale generators by providing a guaranteed price for electricity exported from the generation site.
- On-site generation – the benefit from reducing imports of electricity by using a proportion of the electricity generated on-site.

i. Renewable schemes in Northern Ireland

The renewable obligation is set for the UK as a whole in order to meet the targets set by the renewable energy strategy. The level in Northern Ireland is set at a lower level than that of the rest of the UK. In 2011/2012 Northern Ireland suppliers are required to produce 5.5 ROCs for every 100MWh of energy supplied, GB suppliers in contrast must produce 12.4 ROCs for every 100MWh of energy supplied.

Northern Ireland does not operate a different scheme for small scale generation (<5MW of installed capacity), as such small scale renewable generation contributes to the level of ROCs. Small scale renewable generation currently accounts for around 13% of the total renewable generation in Northern Ireland.

ii. Trading of ROCS

ROCs are a UK specific support mechanism and cannot be traded outside of the UK. OFGEM is responsible for hosting the online trading platform for ROCs[4]. The website also provides historical data on the production of renewable generation in the UK.

2.3 Support schemes in Ireland

The current scheme is known as REFIT (Renewable Energy Feed-In Tariff). This feed-in tariff scheme is a competition for the allocation of support for the construction of certain categories of renewable generation. The scheme allows RES-E generators to secure the necessary investor confidence to finance debts. RES-E generators enter into fifteen years electricity purchase agreements with suppliers at negotiated prices. Via the Public Service Obligation (PSO) levy mechanism, REFIT compensates participating retail electricity suppliers according to the REFIT terms and conditions for the net additional costs attributable to their participation in the scheme and purchase of electricity from the relevant generators in the REFIT scheme. The terms and conditions of the scheme are available on the website of the Department of Communications, Energy and Natural Resources.[5]

The REFIT scheme currently covers onshore wind (large and small scale), small scale hydro, biomass landfill gas and other biomass. Subject to state aid clearance, REFIT will also be offered for anaerobic digestion/high efficiency CHP, ocean (wave and tidal) energy and offshore wind. Participation in the scheme is voluntary for both generators and suppliers.

Prior to the introduction of REFIT, a tender scheme, the Alternative Energy Requirement (AER) scheme was used to support RES-E in Ireland. Under AER, there were six calls for tenders (AER I – AER VI) between the mid-1990s and 2003. AER applications were invited from prospective generators to build, own and operate new wind, hydro, biomass and waste-to-energy facilities. All applications were ranked on the basis of bid price per kilowatt-hour supplied. Successful applicants could enter into Power Purchase Agreements (PPAs) of up to fifteen years with the Public Electricity Supplier (ESB). Whilst the scheme is still in place given the duration covered as above, it is closed to new entrants and has been replaced by the REFIT scheme.

[4] https://www.renewablesandchp.ofgem.gov.uk/

[5] http://www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division/

2.4 Single Electricity Market

Within the context of the All Island Energy Market Development Framework agreed by Ministers in Ireland and Northern Ireland in November 2004, the Single Electricity Market (SEM), the all-island arrangements for the trading of wholesale electricity, went live on the 1 November 2007. The introduction of the SEM was underpinned by new legislation in both Ireland and Northern Ireland, each of which includes provision for joint regulation of the wholesale electricity market arrangements through the SEM Committee as well as movement towards harmonisation of many electricity transmission related matters. The SEM replaces two separate wholesale electricity markets in Ireland and Northern Ireland.

Its design includes wholesale trading arrangements for electricity which incorporate the following key features:

- a gross mandatory pool;
- a system marginal price (SMP) for energy which is set on an unconstrained basis;
- a capacity payment mechanism; and
- a series of rules concerning constraint payments for generators.

The SEM is a gross mandatory pool, meaning that all electricity generation (above a 10MW de minimis threshold) and all imports must be sold to the pool, while all wholesale electricity for distribution or export must be bought from it. Generators submit bids based on their short-run marginal cost (in accordance with the Bidding Code of Practice) of energy production. The energy price is set on the basis of these bids, accounting for Price Taking generation (see below) on an unconstrained basis. In addition to payments for energy provided, generators get capacity payments for making their generating capacity available. Payments for constraints are as set out in the market rules (Trading and Settlement Code) with ancillary services payments also available to generators for defined services[6]. Renewable generators both in Northern Ireland and Ireland participate in the SEM. This means that generators that are located in two different Member States and that have access to different support schemes are participating in the same wholesale electricity market.

In parallel with the development of the SEM, in July of 2005, the Governments of Ireland and Northern Ireland jointly issued a preliminary consultation paper on an all-island '2020 Vision' for renewable energy. The paper sought views on the development of a joint strategy for the provision of renewable energy sourced electricity within the All-island Energy Market leading up to 2020 and beyond, so that consumers, North and South, could continue to benefit from access to sustainable energy supplies provided at a competitive cost. Within the context of the All-island Energy Market Development Framework and the undertaking to develop a Single Electricity Market, views were sought on how the electricity infrastructure on the island might best develop to allow the maximum penetration of renewable energy.

[6] Ref: http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx

The July 2005 consultation paper identified that further information was required on the resource potential for different renewable technologies on the island of Ireland in 2020, the extent to which partially dispatchable and non-dispatchable generation can be accommodated, network development options and the economic implications of the policy options outlined within the paper. A working group was established to specify and oversee the completion of studies that would provide more detailed information on the above issues. The working group recommended an "All Island Grid Study" which was subsequently completed and published in January 2008.[7]

This study examined the impact of different scenarios of wind renewable generation penetration on the electricity system of the island of Ireland in 2020. In the light of the AIGS, and EU renewables targets for Ireland and Northern Ireland for 2020, the Commission for Energy Regulation (CER) and NIAUR (jointly the Regulatory Authorities (the RAs)) under the auspices of the SEM Committee published a discussion paper on the treatment of wind generation in the SEM, given that wind is the dominant form of renewable generation that exists on the island and given the potential for future build in the context of 2020 targets.

A study completed in January 2009 by the RA's assessed the effect of increasing renewable generation penetration on the ability of the SEM to operate efficiently and effectively. The focus of this work has, in particular, been to examine the impact that high levels of wind penetration, and more specifically the generation portfolios contemplated in the AIGS, would have on the existing design and operation of the SEM and on the ways in which generators would be remunerated in 2020. This study found that, for defined inputs, assumptions and scenarios, the SEM design is potentially robust to significant increases in the amount of wind generation on the system, though the marginal nature of the incentives on new generation to enter the market is a potential concern, which suggests that the design will need to be kept under close review in the years to come[8].

a. Energy prices

Energy prices in the SEM are calculated and published ex-post (four days after the event). The SEM uses a complex bidding methodology, whereby all generators are required to submit price/quantity pairs to reflect the production cost of the generator, as well as the cost of starting and the no-load cost of running the plant[9]. Additionally the Bidding Code of Practice (BCOP, AIP-SEM-07-430) sets out the principles behind cost reflective bidding in the SEM. The market price is calculated on a half-hourly basis. The price is calculated to minimise the production cost of meeting demand over the period, with the marginal plant setting the energy price at each half hour period which is termed the System Marginal Price (SMP). Note that this price is set on an unconstrained basis.

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[7] Ref: http://www.dcenr.gov.ie/Energy/Latest+News/All-Island+Grid+Study+Published.htm

[8] Ref: Impact of High levels of Wind Penetration in 2020 on the Single Electricity Market, A Modelling Study by the Regulatory Authorities, January 2009 , http://www.allislandproject.org/GetAttachment.aspx?id=20cff228-2b30-48af-af07-539a3c65523c

[9] This is set out in a generator licence condition requiring "cost reflective bidding in the SEM".

There are a number of classifications of generators in the SEM:

- Predictable Price Maker Generator Unit;
- Variable Price Maker Generator Unit;
- Predictable Price Taker Generator Unit;
- Variable Price Taker Generator Unit;
- Autonomous Generator Unit.

Price takers are not required to submit bids. They receive energy payments for when they are scheduled to run, at the SMP price for the period they run. Only generators that have priority dispatch status can be designated as price takers. All renewable generators are eligible for priority dispatch status. In addition to renewable generators, certain other generators are also eligible to register as price taker generator units in the SEM, i.e. those certified as high efficiency CHP and those that have been afforded priority by a Member State for security of supply reasons as provided for in Directive 96/92/EC (Article 8 (4)).

i. Price Taker Generator Unit

For the purposes of calculating the energy price at any given period the quantity of price-taking generation is netted off actual demand.

ii. Price Maker Generation Unit

There is no prohibition on a price making generator bidding in negative prices (though generators are required to adhere to the BCOP). This potentially allows for certain classifications of generation to bid negative price and theoretically set a negative SMP/ energy price (subject to the price floor). Careful consideration therefore is required with respect to the impact of renewable support schemes on prices in the SEM. In addition to the above, the SEM market rules (the Trading and Settlement Code) provide for the SMP (unconstrained energy price) to be set at the defined Price Floor which is currently set at currently set at - €100/MWh under certain conditions. This negative price floor also acts to stop the SMP (unconstrained energy price) falling below this level.

b. Competing renewable support schemes in one market

As mentioned above renewable generation in the SEM can avail of price taking status given priority dispatch and, as such, that generation is netted off demand for the purposes of deriving energy prices in the SEM.

However, generators that qualify for priority dispatch do not have to register as price takers, and could decide to register as price making generation. (Note that where such generators bid in a price they will be dispatched on the basis of that price as price makers.) Depending on how the different renewable support schemes are incorporated into their bids (noting the requirement to comply with the BCOP) the variance in the renewable support schemes could result in market distortions, in particular it could influence where renewable generation chooses to locate. It is noted that there are some renewable generators on the island of Ireland that are not covered by support schemes and, therefore, would not be in a position to bid into the energy market reflecting such mechanisms.

Since the inception of the SEM on November 1st 2007 no renewable generator has opted to act as a price making generator in the SEM. Therefore, no negative bids into the energy market have been made by renewable generators since the commencement of the SEM.

c. Impact of SEM prices on renewable generation

To date the energy (SMP) price in the SEM has only gone below €0/MWh on one half hour trading period - 21/09/2010 at 3.30am, the price was -€88.12, this happened due to an unintended consequence of the single Ramp Rate calculation in Appendix N of the SEM market rules (the Trading and Settlement Code) that are not accurate to generator capabilities and resulting in a thermal generators' running in terms of Market Schedule Quantity being constrained by an extremely low Ramp Rate. This led to the calculation of an Inter-temporal Ramp Constrained Price[10].

Currently there is no price making generation that has negative production costs (therefore no negative bids are received in the energy market), as such generation participating in the market is rarely exposed to negative SMP/energy prices. This situation is likely to change in the near future as the market is expecting the entry of an energy-from-waste plant. It is expected that the SEM will begin to receive negative bids when this plant enters the market.

This has the potential to increase the number of negative SMP/energy price events in the SEM, and could have a potential impact on the revenues of price-taking renewable generation.

d. Renewable targets

A 2010 study carried out by DETI[11] indicates that in order to meet the renewable target of generation coming from renewable sources by 2020 will be met by a significant increase in intermittent renewable generation volumes. Since intermittent generation is a variable and only partly predictable source of power generation, its massive deployment may require greater levels of flexibility both in the generation mix and in the operation of the power system.

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[10] For further information SEMO published a report into the event: http://www.sem-o.com/Publications/General/Market%20Incident%20Report%20September%2020th%202010%20-%20V1%200.pdf

[11] For further information see:
http://www.detini.gov.uk/determination_of_the_appropriate_form_of_support_for_incentivising_the_development_of_renewable_electricity_generation_in_northern_ireland_

e. On-going monitoring of the market

There are proposed changes in the support mechanisms for renewable generation in GB that could have an impact on renewable generation in Northern Ireland and energy prices in the SEM. DECC is currently considering changes to the support mechanism in GB, one of the proposals put forward is a contract for difference (CfD) approach which would allow generators to pass the risk of price fluctuations to suppliers. HM Treasury have consulted on a proposed carbon price floor.

In addition to this the impact of the Regional Market Integration has to be considered by the SEM Committee, notably the issue of compliance with the FG CACM.
Subsequent to consultation, in August of 2011 the SEM Committee published a decision paper that set out the principles regarding dispatch of generation eligible for priority in dispatch, including but not limited to renewable generators. [12]

In that decision paper the SEM Committee also determined that there is currently no need to make changes to the TSC and that the rules for energy payments and constraint payments to renewable generators do not merit revision at this juncture. The SEM Committee also reiterated its position that a price floor has merit and should remain and noted that the level at which the price floor is set is consulted upon annually and that this will continue.

The SEM Committee has committed to on-going monitoring of the market to ensure that key SEM legal objectives continue to be met and to further examine the causes of changes in the market that jeopardise the achievement of these legal objectives. If and where it is considered that changes are required to the SEM in this context, then consultation will take place on options for addressing the drivers of the issue in question and a regulatory impact assessment will be carried out on changes to the SEM. In this context, the SEM Committee has noted the work being carried out regarding compliance with the FG CACM and the timelines for this compliance.

[12] Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code, SEM Committee Decision Paper, 26th August 2011, SEM-11-062.

3 Case study: Spain – Significant achievement of renewable generation penetration

Spain is characterised by a strong dependency on foreign energy sources. Spain relies on imports for around 80% of consumption, higher than the average of around 50% in the EU-27. Therefore, the development of renewable energy in Spain has a strategic value.

As far as renewable energy resources are concerned, the wind map shows that wind speeds in Spain are lower than the EU average. However, solar radiation is higher than in other EU Member States. The key point for harnessing these resources is technology maturity: wind power, followed by solar PV, are the most developed technologies in the last years.

Political support for renewable energy and stable feed-in tariffs/premiums resulted in a smooth development and industrial deployment in renewable generation. The empirical evidence has shown that support schemes play a key role in encouraging RES development in Member States, with investment appearing to be driven by favourable economic and policy climate more than natural resources.

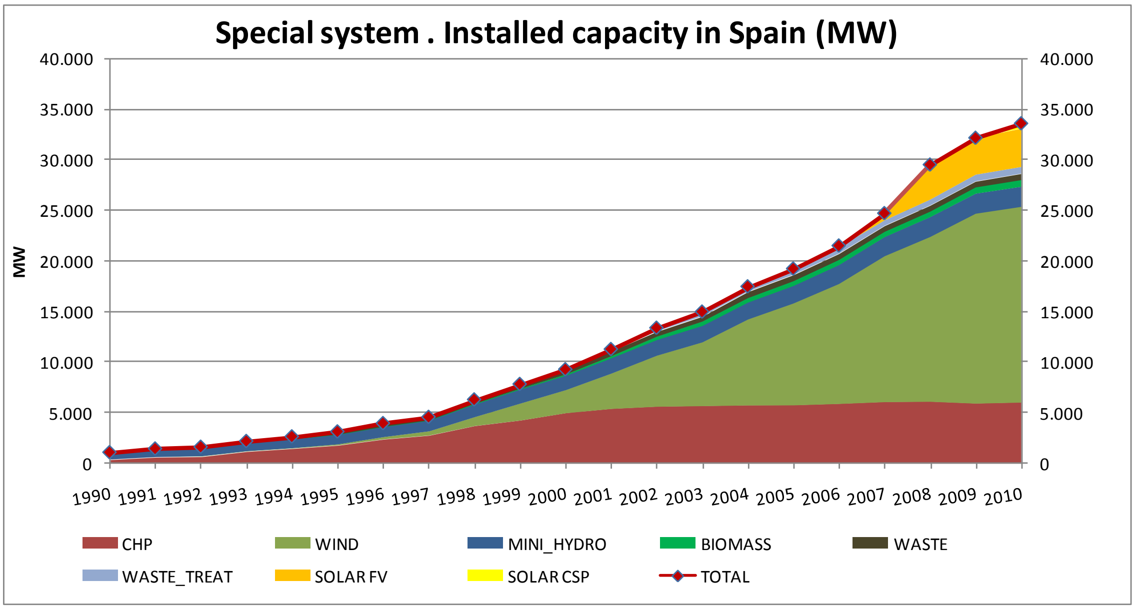

Figure 1 Installed capacities of renewables in Spain under the Special Regime (CHP and renewables)

This scheme has been working in an effective and efficient way for mature renewable technologies such as wind (between 2000 and 2009, installed capacity has grown by 17GW). The wind power capacity installed in Spain represents 20% of the total wind capacity installed in Europe.

Year	Target	Information
1997	-	Electricity Law (Law 54/1997). Long-term target: 29% of 2010 electricity production to be renewable.
1998	-	Royal Decree on "Special regime". Basic framework for renewables.
1999	Nearly 9000 MW of wind farms by 2010	Renewable Energy National Plan
2002	Target: 13000 MW of wind farms by 2011	National Energy Planning
2004	-	Tariffs and premiums are defined (RD 436/2004). Regulatory stability to achieve targets.
2005	Target: 20155 MW of wind farms by 2010	New Renewable Energy Plan
2007		Regulatory Framework Revision approved and establishment of cap and floor remuneration (Royal Decree 661/2007). In 2020, 20% of renewable energy binding target.

Figure 2 Important milestones in the Spanish renewable energy regulation. Source: CNE based on Spanish legislation

In Spain, 90 TWh production received support in 2010 which means 32.6% of total gross electricity production receiving an annual support in 2010 (feed-in tariffs/premiums) of 7016 M€, more than the sum of transmission and distribution revenues.

In terms of infrastructure, the Spanish electricity system has a well meshed network that facilitates the integration of renewable generation, achieving a successful integration of around 20 GW of wind power and 4 GW of solar PV.

The Spanish TSO (REE) can only deny network access to generators in certain situations specified by law. Renewable generators have priority in access, connection and dispatch. However, the increasing commissioning of renewable energy is challenging the reliability of the system, mainly due to the variable character of renewable energy and reduced international interconnections. This has led to outages caused by voltage fluctuations in zones of concentrated installed renewable plants.

High penetration of intermittent generation has increased the need for peaking backup generation capacity, which is currently provided by fossil fuel technologies and hydro plants in Spain.

The TSO manages the renewable output in the electricity system under safe conditions in a number of ways. These include a centralised monitoring and control centre (CECRE), wind forecast tools (SIPREOLICO) and continuous network development which facilitates the integration of renewable generation in the system.

How do the costs of producing renewable energy compare to conventional sources?

Renewable energy development needs extra incentives in order to reach the national targets. With the development of mature technologies and the internalisation of CO_2 costs in conventional thermal plants, renewable energy is getting more and more competitive, but support is still necessary.

In Spain, the weighted average support to renewables in 2010 was 77.7 €/MWh. This extra cost is considered necessary to trigger and maintain investments in RES. The average day-ahead spot market price in 2010 was 37.01 €/MWh.

The Spanish support scheme establishes different goals for each technology. Despite the success in mature technologies, such as wind (equivalent subsidy in 2010 amounted to 45.4 €/MWh), some problems have emerged in the case of immature technologies such as solar PV, a technology that had to be heavily subsidised. The initial solar PV target amounted to 471 MW of installed capacity of PV plants in 2010 but, due to an extremely high FIT (equivalent subsidy in 2010 amounted to 417.1 €/MWh) and significant foreseeable cost reduction, an overinvestment has occurred, with an installed capacity of 3500 MW.

This large installed capacity means important environmental, local and regional benefits. But also involves a cost for the system (the economic impact for consumers is around 2.6 billion € annually). The government decided to update the regulated revenue for some technologies (solar PV plants installed before September 2008 will reduce their support in 2011, 2012 and 2013).

4 Case study: Joint support schemes – Norway and Sweden TGCs

4.1 Renewables in Sweden

Sweden's Green Electricity certificate scheme was launched in 2003. The aim is to increase the production of electricity from renewable energy sources with 25 TWh in relation to the production volume of electricity from renewable energy sources in 2002. The Electricity production in Sweden that qualified for tradable green certificates (TGCs) in 2009 amounted to 15.6 TWh, which is 9.06 TWh higher than corresponding production in 2002. The increase consists primarily of production from biofuels. A higher share of renewable fuels has been used for generation in combination with an increase in capacity of the existing biofuel plants.

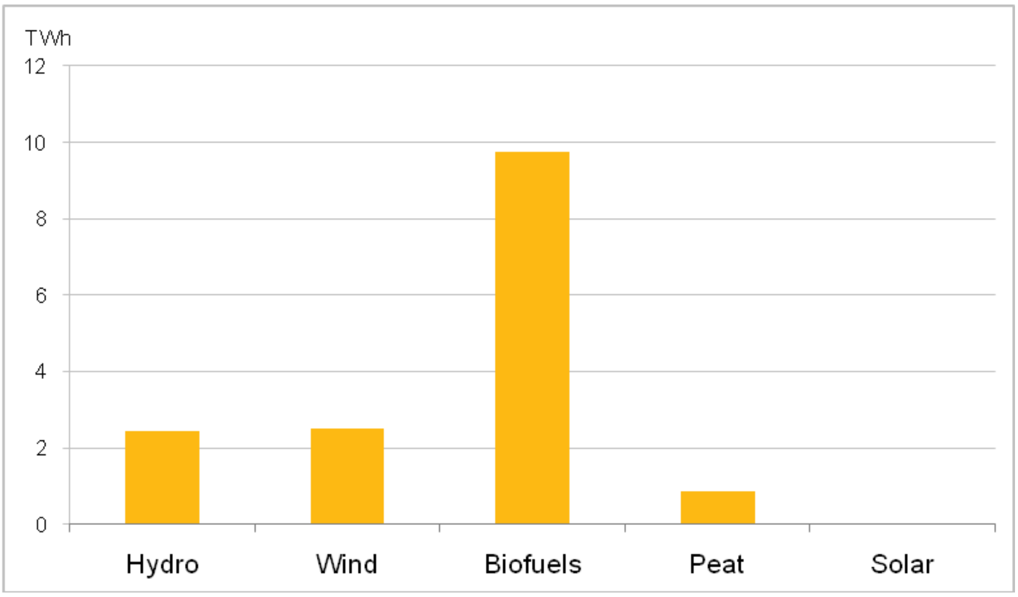

Figure 3 Electricity production 2009 - Renewable and peat (MWh).

Source: Swedish Energy Agency

4.2 A joint system – one of the cooperation mechanisms

Joint support schemes are one of the cooperation mechanisms that EU and EEA countries can use to achieve their national targets of renewable consumption. In Sweden and Norway the scheme under development consists of a Green Electricity certificate system. Several of the parameters in the design of such a scheme have been negotiated into an agreement.

In addition to the design-related issues, the agreement handles matters on how energy from renewables will be allocated between the two countries. The RES Directive[13] stipulates that Member States with a joint support scheme may distribute a certain amount of energy from renewable sources produced in their territory either through a statistical transfer or through a distribution rule agreed by the participating Member States. Sweden and Norway will use the distribution rule when allocating the amount of energy from renewable sources between them. Through negotiations, Norway and Sweden have agreed to split the 26.4 TWh in equal parts when reporting on the progress towards reaching the renewable energy targets defined in the RES Directive.

4.3 Pros and cons of a joint scheme

According to the International Energy Agency's assessment, a joint market will decrease the long-term risks of high prices for electricity certificates. Initially, changes towards a joint market might to some extent create uncertainty for the investors, which in turn might lead to somewhat lower short term certificate prices. A larger market will also lead to a more stable, liquid and generally better functioning market for electricity certificates. The system will also provide an opportunity to achieve both countries' objectives at lower cost, since production is likely be built where it is most cost-efficient. A joint support scheme can provide further benefits as it covers a larger geographical area and this might increase the incentives for firms to invest in renewable power generation.

4.4 A joint support scheme between Sweden and Norway - how will it work?

The electricity certificate scheme is a market-based support system that acknowledges competition between renewable energy sources. The scheme creates a supply and demand for certificates determining their price (i.e. the support) which is the same regardless of the type of renewable energy source used. The scheme creates a situation in which the cheapest method of producing renewable electricity is favoured. The certificate system gives the renewable electricity an increased value, as the producer can sell the certificate as well as the electricity. Production plants that meet the requirements receive one certificate unit for each megawatt-hour (MWh) of produced electricity. Production from the following energy sources are entitled to certificates:

- Wind power
- Solar energy
- Wave energy

[13] 2009/28/EC

- Geothermal energy
- Biofuels[14]
- Peat, when burnt in CHP plants
- Hydro power

Sweden and Norway are in the process of creating a joint system for electricity certificates. The two countries have reached an agreement which sets the basis of the joint market. In the process of creating a well-functioning electricity certificate market, some basic functions and rules need to be harmonised while other areas can be handled by the market. According to the Swedish Energy Agency the following main factors need to be coordinated:

- key principle of what constitutes legitimate certificates of production;
- how long the plants may be included in the system;
- electricity certificates' legal status;
- other non-competitively neutral support systems;
- similar support and control functions;
- exit from the market is regulated.

4.5 Quota

The demand for certificates is created by the obligation for electricity suppliers to purchase certificates corresponding to a certain proportion (quota) of their electricity sales. In addition, the quota obligation also applies to electricity-intensive companies and electricity users who have used electricity that they have produced, imported or purchased on the Nordic power exchange.

Since Sweden started supporting RES generation through an electricity certificates scheme in 2003, and Norway will start in 2012, the quotas in the two countries differ from each other. The quotas set in Sweden are based on the target of 25 TWh of renewable energy in 2020[15]. In Norway the quotas are based on a target of 13.2 TWh new production from 2012 until 2020. By the end of 2011 the electricity production from renewables in Sweden is expected to have grown by 11.8 TWh compared to 2002. In order to reach the target Sweden has designed the quota curve to stimulate expansion of 13.2 TWh in the period 2012 to 2020.

[14] Biofuels, as defined in the Ordinance (2003:120) Concerning Electricity Certificates.

[15] The target is set relative to the production level in 2002 and is determined by the Act (2003:113) concerning certificates.

4.6 Expected outcome from a joint electricity certificate scheme

Calculations made by the Swedish Energy Agency show that the shared ambition of Norway and Sweden may lead to an increased hydro generation in Norway, increased biomass generation in Sweden and onshore wind in both countries. Wind power will represent more than half of the additional production. The calculations show that electricity production in Sweden in 2020 might be slightly lower in a joint system than in a separate Swedish system. This is partly due to the assumption of equal distribution of wind expansion between the two Member States while the potential for new hydro power in Norway is higher than the potential for further expansion of biomass in Sweden.

Having a market-based support mechanism, Sweden and Norway will compete on equal terms for the new production that the system is designed to bring forward. Because of this, it is not clear where the new production will be built. Though it is expected that wind and hydro power will mostly be built in Norway, it is not possible to be precise on the exact quantities. The costs of realising wind power are assumed to be more or less the same in Norway and Sweden, but Norway has a larger potential for new hydro power production. In Sweden, on the other hand, it is expected that the certificate scheme will lead to relatively more investments in bio-energy power plants than in Norway. Altogether it is likely that Sweden and Norway get more or less an equal share of the new production.

4.7 Norwegian perspective in a joint certificate system

In 2009 Norway produced around 97% of electricity from renewables. Nearly all of the renewable production comes from hydro power installations, but over the past ten years the wind power industry in Norway has grown steadily. Even so, the total wind power production does not represent more than 1% of the total production.

Of the renewable technologies, only wind power receives financial support in Norway today. The state owned enterprise Enova grants wind power projects investment support ahead of the building phase of a project. This scheme has been Norway’s way of supporting wind power since 2001, and a total of €330 million has been paid out, helping to realise 2.1 TWh of wind-based electricity production in 2010.

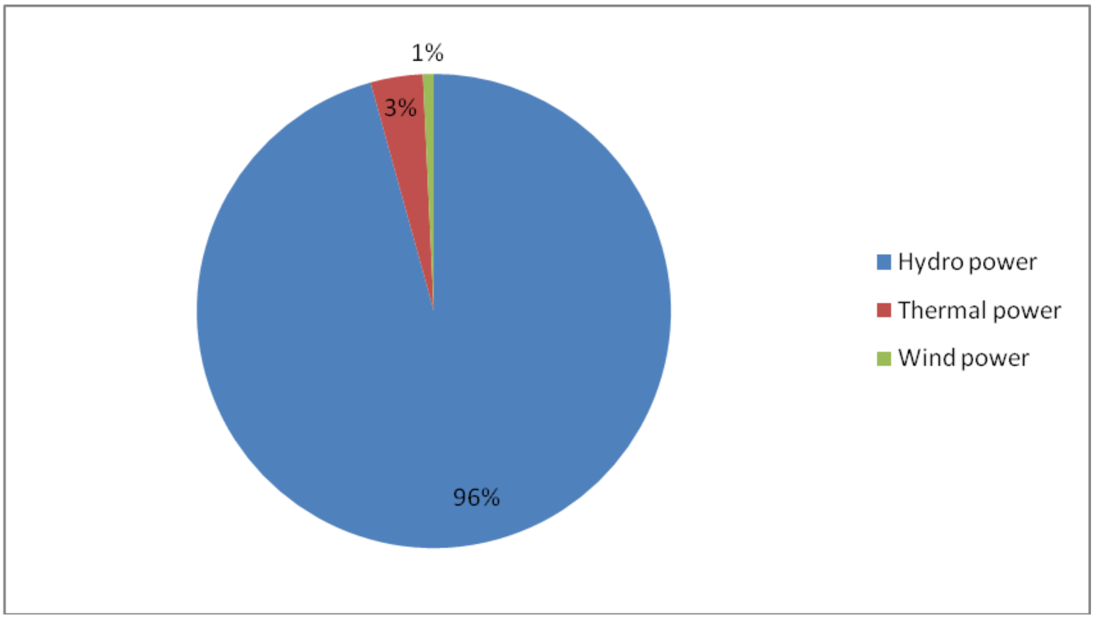

Figure 4 Production mix in Norway in 2009. 96% of the electricity production came from hydro power. Source: Norwegian Water Resources and Energy Directorate

From 1 January 2012 Norway will be supporting investments in renewable electricity production through a joint Swedish-Norwegian electricity certificate market. From 2012 until 2020 the aim of the certificate market is to finance 13.2 TWh of new production in Norway, matching Sweden's target. The system will be technology neutral unlike the case with the Enova system that only supports wind power. There are several reasons why Norway wants to implement the certificate system as the way of supporting renewable technologies. Firstly it is part of Norway's climate policy to increase the proportion of energy consumption met from renewables. In addition, Norway will have to meet its EU obligation to increase its share by 2020, which induces Norway to increase its share of renewable energy from 58% in 2005 to 67.5% in 2020. Secondly the certificate market will hopefully bring forward more electricity production which in turn increases the security of supply in Norway and reduces electricity prices. The third reason for joining Sweden in the certificate market is to further develop the renewable industry in Norway.

5 Case study: Switching of support schemes in Italy

5.1 Recent developments of RES support schemes in Italy: from a TGCs mechanism to a feed-in tariff system

Overview of Italy's RES support schemes

In the last two decades Italy has used both a quota obligation system and feed-in tariffs (FITs) to promote renewable energy sources (RES).

The first mechanism for the promotion of RES, a **FIT** system, was introduced in 1992, which promotes the construction of plants for generation of electricity from renewable and/or so-called "assimilated" sources[16], warranting for eight years an incentivising remuneration on top of avoided costs for plant construction, operation and maintenance and fuel. In 2001, this was withdrawn by the *Gestore dei Servizi Energetici (GSE)*, a public operator responsible for energy services management that covers a central role in the mechanisms of RES energy promotion in Italy. Energy is offered by the *GSE* in the day-ahead market; operators holding an allocation (as a result of auctioning procedures) stipulate a contract for differences with the *GSE* that determines the price of energy corresponding to their allocations. The difference between the purchasing and the selling energy price for *GSE* is financed by a tariff component paid by all end-users.

A **feed-in premium** (FIP) system was introduced in 2005, in order to promote the production of energy from photovoltaic plants. In particular, photovoltaic energy receives a 20 year stable remuneration additional to the selling price. In 2010, the feed-in premium was changed so that payments vary depending on the classification of the plant, plant capacity and the date of start of operation. The mechanism distinguishes between three basic types of photovoltaic plants: solar photovoltaic plants, integrated photovoltaic plants with innovative features[17] and solar concentration plants. Limits have been set on the total capacity of photovoltaic plants that may benefit from the new regime, depending on the classification of the plants.

In addition to these regimes, in 2002 Italy implemented a market mechanism for the promotion of RES, based on tradable green certificates (**TGCs**), aimed at gradually replacing the FIT support mechanism. Beginning in 2002, producers and importers of electricity from non-renewable sources are required to yearly inject into the power system a given quota of RES energy[18]. Such an obligation can be met both by producing/importing renewable energy

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[16] Assimilated energy is energy from plants in cogeneration and plants using process heat and other products deriving from a transformation process.

[17] Plants composed of panels with technologically innovative features, developed specifically to substitute an architectural feature of a building.

[18] This was fixed for 2002 as 2% quota of produced or imported electricity from non-renewable sources in the previous year. From 2004 to 2006, the quota has been increased by 0.35 percentage points per annum, while during the period 2007-2012, the share is planned to rise by 0.75 percentage points per year.

and by purchasing TGCs relative to the production of electricity from renewable sources.

The TGCs are issued by the *GSE* to operators whose plants have obtained the qualification of renewable producer from the *GSE* or in favour of the same *GSE*, for the FIT energy it withdraws. TGCs are valid for three years and from the end of 2007 correspond to 1 MWh of energy[19].

The previous legal framework was strongly modified so that production of electricity from renewable sources by plants entered into exercise or repowered between 1999 to 2007 are granted TGCs for the first twelve years of operation. Eligible plants benefit from TGCs in a number calculated in proportion to the net production of electricity, without differentiating between the different energy sources. RES plants entered into exercise or repowered after the beginning of 2008 have the right to receive TGCs for the first fifteen years of operation; the number of certificates delivered is determined as the product of the net energy generated and a coefficient, differentiated by plant type. The production of electricity by plants with capacity lower than 1MW (0.2MW for wind power plants) and entered into operation after December 2007, as an alternative to the issuing of TGCs, can benefit from a FIT. This tariff is differentiated by RES type and granted for a period of fifteen years.

Considering 2009-2010, 39% of TGCs were issued for production by hydro plants, while the share of wind production was about 31%. Another 24-25% of certificates were issued for biomass and waste power plants production.

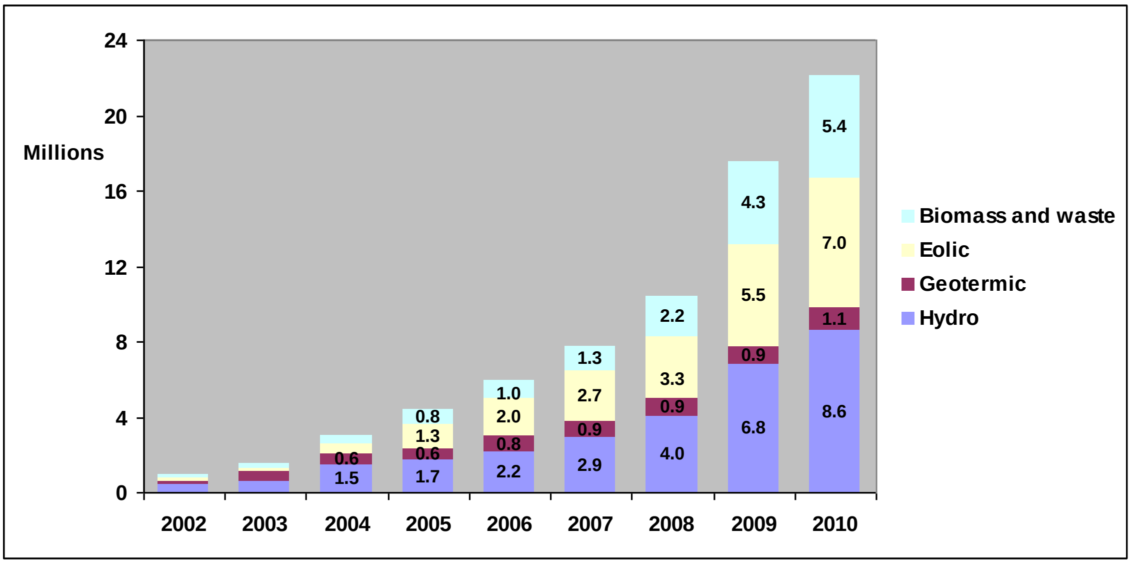

Figure 5 Number of issued TGCs by source (size CV=1 MWh). Note: 2010 data are estimated. Eolic = Wind power, Geotermic = Geothermal. Source: GSE

[19] Previously, the size of certificates was 100MWh in the first years of the mechanism and, since 2004, it is 50 MWh.

The *Gestore dei Mercati Energetici (GME)*, public operator that manages the Italian power exchange, has organised a specific market for certificates trading. This had been in operation since March 2003 in addition to bilateral negotiations. In this market different subjects can operate as buyers or sellers: the *GSE,* domestic and foreign producers, and importers and traders. The *GSE* offers a number of TGCs in the market that are required to ensure the balancing between demand and supply in case of lack of certificates offered by private operators. For these certificates, a reference price is fixed in advance and updated yearly.

Since 2004, however, most of the demand has been covered by transactions taking place outside the organised market.

5.2 The evolution of the TGC mechanism

A problem that has hampered an efficient functioning of the TGC market since 2007 is a structural condition of excess of supply. The supply surplus grew from 2.2TWh in 2007 to about 8.1TWh in 2008, reaching a maximum of 10.3TWh in 2009. This surplus was originated by a relevant increase of TGCs issued in favour of RES producers.

Another feature characterising the TGCs market is the high level of concentration both on demand and supply side. About three quarters of the demand is covered by the five main operators that represent also about half of the total supply. On the supply side however, there are emerging medium-size operators, favouring a decrease of market concentration during the last two years, alongside main operators and very small enterprises.

Criticism on the efficiency of the TGC market as a mechanism to incentivise RES also originated from the evaluation of its costs for the energy system. In order to evaluate the total costs of the support scheme, two components should be considered. The first component derives from the costs borne by producers and importers in order to comply with their obligations. Such costs are covered by the operators from selling electricity. As a result of the pass-through of incurred costs in the offers submitted by operators in the day-ahead market, based on the system marginal price rule, production exempted or excluded from the quota obligation is warranted an extra-income, without bearing additional costs. Therefore, the first component of total costs is indirectly charged to end users through electricity prices. As regards 2009, the related cost was estimated to amount to about €650 million.

The second component arises from the TGCs withdrawal obligation placed on the *GSE*. Since 2008 the *GSE*, upon request of the producer, is obliged to withdraw by June of each year the certificates expiring in that year resulting unnecessary to satisfy the obligations. This was modified for the period 2009-2011, enabling operators to ask for the withdrawal of the certificates issued in the three previous years, regardless of their expiration date. Consistently, the withdrawal price was determined as the average price of certificates traded during the three previous years. In general terms, the price of TGCs sold by the *GSE* and the withdrawal price represent respectively the maximum and minimum reference values for the TGC market.

With reference to 2009 however, the withdrawal price (€98/MWh) was higher than the price of certificates sold by the *GSE* (€88.66/MWh) that should represent the upper limit of TGCs price. As a consequence, the owners of TGCs were incentivised to require the withdrawal of their certificates, significantly increasing the cost borne by end-users. More in general, current market conditions, characterised by a significant level of oversupply, naturally reflected on the demand of withdrawals by operators. During 2010 the *GSE* withdrew TGCs corresponding to about 9.9TWh. The costs related to the *GSE* withdrawal obligation are covered by a specific component of the end-users' bills. These costs significantly increased since 2008, due to the worsening of the condition of excess of supply; for 2010, they amounted to about €940 million.

5.3 The revision of RES support schemes

The Italian experience highlighted the existence of difficulties and obstacles in the implementation of a proper market mechanism for RES energy promotion based on TGCs. From this point of view, major concerns probably derived from the frequent revision of the mechanism, in particular during the last two years, which resulted in a confusing and substantially inorganic framework.

In particular, the main critical aspects that could have compromised the effectiveness of the mechanism are the following:

- The mandatory quota of renewable sources has probably been set too low to guarantee a proper functioning of the market. As pointed out before, this has prompted a situation of structural excess of supply, that resulted in a significant decrease of the price of TGCs;
- Beforehand, the TGCs market price has been strictly in line with the reference price fixed by the *GSE*; as a consequence, the Italian TGC market has proved not to function as a real market since both prices and quantities have been, to a large extent, administratively fixed;
- The market organised by the *GME* for certificates trading has proved not to be very liquid, since less than 10% of certificates have been recently traded on it; as a result the price volatility in this market is significantly increasing;
- The obligation of withdrawal by the *GSE*, in a context of excess of supply in the market, has turned out to be very expensive for the energy system, increasing the costs borne by end-users through their electricity bills;
- Frequent updating of the mechanism has undermined its trustworthiness, hampering the realisation of investments by market operators in the medium and long-term.

These problems in the functioning of the TGC market has stimulated a debate aimed at evaluating the pros and cons of a revision of the support system for RES in the electricity sector, in order to reach the objectives of RES penetration on total energy consumption fixed by the RES Directive[20]. In particular, it emerged clearly that a regulatory intervention was required in order to simplify the support system for RES in Italy. Such system, as a matter of fact, is the result of the stratification of different mechanisms introduced at different times,

[20] The target for Italy corresponds to 17% of total energy consumed.

one of which, namely the FIT, will be gradually phased-out by 2020.

The Italian Government implemented the RES Directive in March 2011 which deeply revises the RES incentivisation system in Italy, stating the gradual phase-out of the TGC mechanism, to be completed by 2015, and the definition of a new system, operative from January 2013, for renewable energy promotion based on FITs.

As concerns the TGCs, further legislation will define the procedures for the transition to the new support scheme. In particular the procedures for replacing the right to receive TGCs after 2015 with the right to take part in the new RES promotion mechanisms for the remaining period, so as to preserve the return on investments. The *GSE* will withdraw TGCs issued from 2011 to 2015 exceeding those needed to respect quota obligations, at a price corresponding to 78% of the reference price previously determined.

The new support scheme (**FIT**) was defined after a consultation process with all relevant stakeholders and was considered by the Government to be in line with European and international best practices. Eligible plants will have to be entered into operation after 31 December 2012. Even rebuilt and repowered plants (with reference to the additional production) and mixed plants (with reference to the production from RES) are admitted to the new support scheme.

This will introduce a fixed FIT for plants with capacity lower than 5 MW and a FIT system based on the results of auctions for plants with capacity higher than 5 MW. Auctions will be organised by the *GSE* and will be carried out respecting a power limit differentiated by energy source or plant type. The tariffs warranted to each participant will be those resulting from the competitive procedure, in the form of a descending-bid auction, whose details will be defined by further provisions. A minimum value of the tariff will be set warranting a minimum return on investments. Further provisions will determine the minimum requirements relative to projects and the financial strength of participants and will define proper mechanisms to guarantee the realisation of authorised plants, introducing a timeframe for their entry into service.

As regards to small plants, the FIT warrants a fixed return on investment, avoiding the price risk related to a market mechanism and facilitates the access to credit.

6 Case study: Support in the Czech Republic

The Czech Republic has had FITs since 2001 with the Energy Regulatory Office (ERO) setting tariffs but without a RES target. There was a lack of regulatory certainty with the support scheme as there was no obligatory framework set in law which meant that investors had no long-term guarantee to obtain finance from banks. This led to the majority of new capacity coming from small hydro plants as this technology has a historical background in the country so banks were willing to lend, despite potential for new hydro being limited.

After the Czech Republic joined the EU in 2004, a target was set for RES-E at 8% of gross national consumption to be achieved by 2010. This was a high target as RES in 2004 was only 3.8%. Since 2005, producers could choose between two types of support: FIT and green bonuses. FIT provided a fixed rate and a 15 years payback period with a maximum of a 5% decrease yearly. With green bonuses the producer gets paid for producing. This does not imply long-term price guarantees but higher profits are possible.

The high level of FIT for Solar PV attracted very high demand for support and resulted in substantial increase in installed capacity. This was also due to investment costs falling rapidly (30-40% per year), while ERO was only able to make cuts of 5% a year. This resulted in a substantial cost for the consumer and led the Government to consider a major cut back in the level of support in 2010. This led to amendments being made to the Green Act in 2010 that allowed the 5% decrease to apply only if return on investments is shorter than 11 years. Besides, new installations over 30kW are subject to support from March 2011 and a tax is now imposed on installations commissioned in 2009 and 2010 to cover the negative impacts on final customers' prices.

The ERO estimated that the real price for meeting extra cost incurred for support of RES in 2011 will be 24€/MWh, while the current price is 15€/MWh after intervention from the Government.

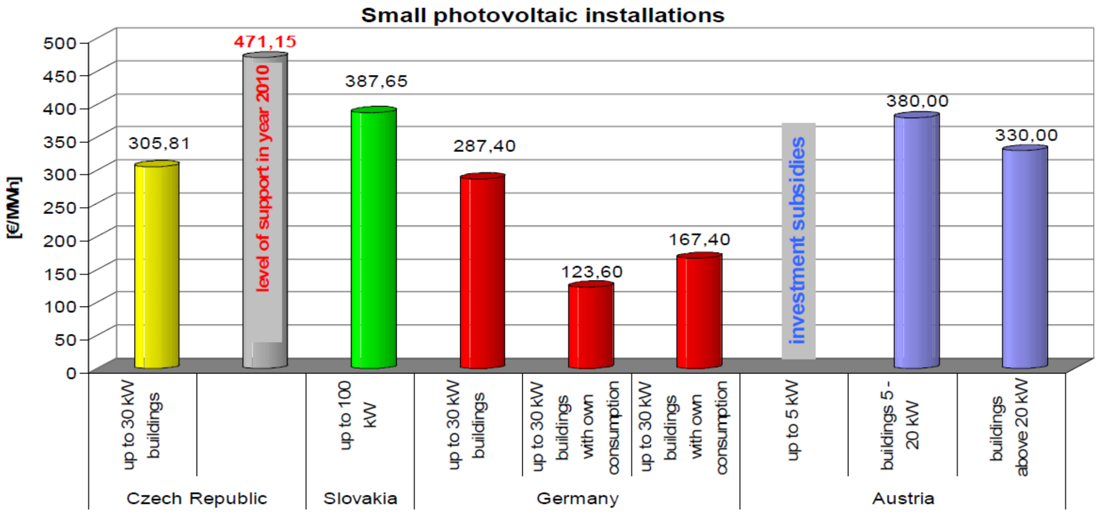

Figure 6 FIT for small PV in neighbouring countries to the Czech Republic in 2011. Source: ERO

There is evidence that investments concentrated proportionally more in the Czech Republic than in neighbouring countries resulted in neighbouring countries offering a lower level of support.

In the future, it is expected that certain aspects of the Green Act will be modified. This will retain the main characteristics of the current system but will create a “dedicated trader” for RES. Alongside this, FIT will only apply to small installations and extra costs will be calculated from real hourly spot prices rather than estimated yearly price of electricity as the current system does.